June 29, 2005

OIL AND GAS DOCKET NO. 8A-0240026

THE APPLICATION OF SAMSON LONE STAR LP TO DISPOSE OF OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL OR GAS, CHRISTOVA STITT LEASE WELL NO. 2D, BROWNFIELD, SOUTH (CANYON) FIELD, TERRY COUNTY, TEXAS

HEARD BY: Thomas H. Richter, P.E., Technical Examiner
Marshall Enquist, Hearings Examiner

APPLICANT:	**REPRESENTING:**
Glenn E. Johnson, Attorney	Samson Lone Star LP
Randal L. Maxwell	

PROTESTANT:	
George C. Neale, Attorney	S.K. Rogers Oil
Greg Cloud	
Kirk Rogers	
Bob Lacock	

PROCEDURAL HISTORY

Date of Application:	August 31, 2004
Date of Notice:	October 15, 2004
Date of Hearing:	November 30 & December 15, 2004
Date of Transcript:	December 30, 2004
Record Closed:	February 1, 2005
Proposal For Decision Issued:	June 29, 2005

EXAMINERS' REPORT AND PROPOSAL FOR DECISION
STATEMENT OF THE CASE

This is the application of Samson Lone Star LP to amend its existing disposal permit to increase the disposal volume and pressure for its Christova Stitt Lease Well No. 2D. The subject well has been a permitted disposal well since 1973 and is used solely for the disposal needs of Samson's leases. The protestant, S.K. Rogers Oil, has a producing well over one-half mile away and believes the increased pressure and volume will adversely affect its well because of fluid migration /crossflow beyond the disposal interval.

DISCUSSION OF THE EVIDENCE

WELL COMPLETION HISTORY

The subject well was originally permitted, March 1, 1973, Permit No. 03832, as a disposal well to Union Oil Company of California in the interval from 5,266' to 5,391' subsurface depth and a maximum surface pressure of 1000 psig. Permits issued at that time did not set volume limits. Part of the permit's requirement was to perform a block squeeze at approximately 5265'. The well was perforated at 5700' and 4210', the latter being inside the 8 5/8" intermediate string of casing. The permit was amended June 8, 1983 (Union Oil), to enlarge the disposal interval from 4,706' to 7,550' and increase the maximum surface injection pressure to 1500 psig. The full interval was not perforated. Two cement retainers were drilled out and perforations from 5,420' to 5,590' added. A total of 256' of the formation is perforated. On April 19, 1990, the permit was again amended (Union Oil) to increase the maximum injection pressure to 1,800 psig and established a maximum disposal volume of 2,000 BWPD. Samson acquired the subject well in February 2004. Samson now proposes that the maximum disposal volume be increased to 6,000 BWPD and increase the maximum surface injection pressure to 2,350 psig. The well is completed as follows:

- Surface casing (11-3/4") is set at 332' and cemented from the casing shoe to the ground surface.
- Intermediate casing (8-5/8") is set at 4,730' and cemented from the casing shoe to a calculated top of 3,523'.
- Longstring casing (5-½") is set at 10,114' and cement from the casing shoe to a calculated top of 3,903'.
- Tubing (2-3/8") is set at 5,155' on an Otis Permalatch Packer at 5,161'. The perforated interval is from 5,266' to 5,590' in the San Andres Formation.
- The depth to the base of the deepest fresh water is 300'.

APPLICANT'S EVIDENCE

Samson asserts that the S.K. Rogers Oil , Schrecengost "B" Lease Well No. 1 ("the Roger's well") is over a half a mile away and will be unaffected. The San Andres Formation, the disposal zone, by nature contains corrosive water and this fact was/is known by all operators. Many wells have been completed to the Canyon, Strawn and Fusselman Formations without cement across the San Andres interval, hence, corrosive casing problems occurred and will occur. Numerous wells dispose of produced water into the San Andres Formation in Terry County and surrounding county areas. Maximum volume rates range from 300 to 20,000 BWPD and maximum permitted disposal pressures range from 2,000 to 2,550 psig.

There are no producing wells within the 1/4 mile required area of review. There are four plugged and abandoned wells within the 1/4 mile review area.

Samson asserts that additional disposal capacity is essential for the production of additional reserves. Samson reviewed its five leases that the subject disposal well serves for the 4 month period from July - October 2004 to determine the amount of lease shut-in/downtime because of the subject disposal well was either at capacity or other problems. The monthly averages for total downtime of the producing leases ranged from 23% - 33% of the time. It is estimated at the current disposal capacity, the remaining recoverable reserves from the producing wells is 449.3 MBO. If the increased volume capacity is approved for the subject well, the estimated remaining recoverable reserves would be 714.9 MBO. Thus an estimated additional 265.6 MBO will be recovered. In addition, other currently shut-in wells potentially may be tested and placed back on production if disposal capacity in increased. The water from the five leases is piped to a central location where it is pumped to Samson's two disposal wells: the Gladys Flache or the subject disposal well. When volume capacity is reached, producing wells on the leases must be shut-in.

Since 1973, the subject well has injected 6.19 MMBW.[1] Well log analysis shows there are 40.5' of gross interval in the upper zone with an average porosity of 7%. The lower 215' show an average porosity of 14.5 % for a weighted average porosity of 13.4% for the entire 256' interval. Volumetric analysis to determine the water front calculates that the invaded area around the Stitt No. 2D to be 24 acres (assumes radial flow for 573'). The produced water that has been injected has not even reached the Rogers well (approx. 3300' away). Assuming that the volume is increased to 6,000 BWPD and injected at that rate for 10 years (28.1 MMBW), the invaded area would be 107 acres, a radius of 1,220', a distance that would not even encounter an existing or a plugged well. Any casing problems that wells have had is because of the natural corrosive nature of the San Andres water and because those operators did not place cement across the San Andres interval.

Samson asserts, from reservoir engineering calculations, that any increased formation pressure resulting from injection is insignificant. Superposition analysis, a reservoir engineering calculation that is based on changing rates, calculates the reservoir pressure at the Roger's Schrecengost well would be 70 psi greater at 2628 psi as of the end of 2004. Increasing the volume to 6000 BWPD and assuming that this volume is injected everyday for 10 years, the pressure would be 2846 psi or 288 psi more. After 20 years the pressure increase would be 2880 psi or 322 psi greater. External/internal corrosion would be the most likely cause of a casing failure, not such a small external pressure increase to 2,880 psi that is far below the designed collapse pressure of casing.

Rogers has complained of the numerous casing leaks that its Shrecengost "B" Well No. 1 has had between 1992 and 1998. This well produces from the Canyon Formation and is perforated from 9,965' to 9,992'. The well was completed, like so many other wells, with no cement across the San Andres Formation interval. The well had its first casing leak approximately 5 years after it was completed. The casing leaks occurred between 5,383' to 5,848' subsurface depth. In 1998, Rogers ran a 4" partial liner (4,646' to 6,559') inside the longstring casing across the San Andres Formation interval and cemented it in place. There have been no casing leaks in that well since that time. Casing leaks and subsequent repair expenses are the price one pays for not cementing casing across such a formation interval containing naturally occurring corrosive water. It should be noted that Rogers was not the operator of the Shrecengost "B" Well No. 1 when it was drilled and completed.

[1] The previous operator was injecting in violation (excess) of its permitted volume 3000-3500 BWPD. When Samson took over the well, it has stayed under 2000 BWPD (1300-1800 BWPD).

PROTESTANT'S EVIDENCE

S.K. Rogers operates the only active producing well in the Brownfield, South (Canyon) Field. Rogers believes that its well has been and is currently being adversely affected by disposal from the Samson, Stitt Well No. 2D. Increasing the pressure and volume will only exacerbate the problem. The Shrecengost "B" Well No. 1 has had numerous casing leaks and is approximately 3,300' from the subject disposal well. The San Andres interval in the Shrecengost well is from 5370' to 6040' (the *perforated* injection interval in the Stitt Disposal well is 5266' to 5590'). The casing leaks in the Shrecengost well have been within this San Andres interval. Within this 3,300' radius, there are two other wells that have had casing leak problems. In addition there are two other wells farther outside the 3300' radius that have had casing leak problems. Also, there are three other wells within the 3,300' radius that were plugged and abandoned by the previous operator, Unocal, that probably had San Andres casing leaks. Further it is believed that in addition to the casing leak problems, there are wells that are within the 3300' radius where there is a material concern of crossflow between the San Andres and the Canyon formation.

The San Andres Formation is laterally continuous across the entire area. It is not productive nor subject to depletion and therefore was at original reservoir pressure of 2,588 psi before injection. Any injection will only increase the reservoir pressure which would cause casing leaks or casing collapse problems and potential crossflow problems. Most of the wells completed in the Canyon, Fusselman and Strawn do not have cement from the producing pay zones back through the San Andres zone. Rogers prepared a chronological listing of the wells in the area that have had casing leak problems or cross flow problems because of casing leaks. See attached Roger's Exhibit No. 2 for well location reference.

1. The Seaton No. 2 (outside the 3300 radius) had a casing leak in 1986 within the SA interval.

2. In 1989, the Ramsuer No. 1 (outside the 3300 radius had a casing leak with in the SA. The well was completed in the Fusselman. When a plug was placed over the Fusselman to protect it during the repair, the well flowed 100 BWPD which indicates a positive pressure increase in the SA.

3. In 1990, the Seaton No. 1 (within the 3300' radius) isolated 2 casing leaks that were below the SA interval. It is believed the SA water was migrating down the casing formation annulus that caused the leaks.

4. In 1991, the Ramsuer No. 1 (outside the 3300 radius) ran a full length liner from the surface to 11,000' due to casing leaks.

5. In 1992, the Shrecengost "B" Well No. 1 experienced its first casing leak within the SA. The previous operator squeezed the casing leak twice. In 1994, Rogers obtained the well and performed its own squeeze job across the same SA interval. When a plug was placed across the Canyon zone during repairs, the surface tubing pressure was 100 psig and the casing pressure was 200 psig which indicates the SA was much higher than its original reservoir pressure. Shortly there after, 2 more squeeze jobs were performed on the well at other SA intervals. This was a recorded SA pressure 15 years ago. Continued injection into the SA will only increase the SA over original reservoir conditions.

6. In 1994, the Stitt No. 3 (within the 3300 radius) was plugged due to a probable casing leak as drilling mud was coming out the 5 ½" casing.

7. In 1994, the Laura Cotten No. 1 (within the 3300' radius) produced drilling mud and has been shut-in since 1999. Samson found casing pits from 7228' to 7730' and a casing leak at 5742'. There is no indication that Samson has ever

placed any type of plug over the Canyon perforations and thus crossflow from the SA to the Canyon could still be occurring.

8. In 1994, the Brazos Petroleum, Bevers No. 1 (within the 3300' radius) was plugged and the report shows that 2 7/8" tubing was left in the hole at a depth of 5,332' (the SA interval). Rogers concludes that the casing collapsed, Brazos had to cut it off, and cement it in place.

9. In 1995, the Stitt No. 1 (within the 3300' radius) Rogers believes developed a casing leak that caused cross flow into the Canyon as production changed from 3.2 BOPD, 90 MCFD and 30 BWPD to “0" oil. The well was plugged.

10. In 1995, within a month of the Stitt No. 1 casing leak, the Bison, Bill McGowan No. 1 (within the 3300 radius) watered-out. Rogers believes this was due to crossflow from the SA into the Canyon.

11 In May 1995, within a few months, the Laura Cotten No. 1 (within the 3300 radius) watered out. Oil production was not reported again until December 1995.

12. In 1996, the production casing in the Seaton No. 2 (within the 3300 radius) collapsed at the SA interval. A 5 ½" liner was run.

13. In 1997, the Rogers Shrecengost well had to have a workover because of a production drop, the tubing anchor got stuck at the SA interval because of a casing leak or slightly collapsed casing. In January 1998, a partial 4" liner was cemented in the well.

These wells have had casing leaks, some watered out prematurely, and production was never fully restored after the casing leak repair and have thus lost thousands of barrels of otherwise recoverable reserves. Rogers estimates that it has lost 285,000 BO from its own well because of casing leaks in the well.

Rogers believes that the Canyon horizon may be open in the subject disposal well. The injection interval is permitted to 7,550'. There were two cement retainers in the well when the it was permitted. In 1984 Unocal drilled out the two cement retainers and added perforations from 5420' to 5590'. Completion reports do not show any inside casing plugs from the injection packer depth at 5161' down to the cement plug on the Canyon at 9929'. If there were a casing leak below the San Andres interval, injected water could possibly migrate into the Canyon zone. Roger’s asserts the actual injection interval in the subject disposal well is from the tubing-packer setting depth of 5161' to 9929' and not 7550'.

Further, the disposal permit required a squeeze job above and below the San Andres Formation interval. Pursuant to a Unocal Repair Workover Report, Unocal perforated at 5,700' and 4,210' in an attempt to block squeeze the San Andres.[2] This initial attempt was unsuccessful pursuant to a temperature survey run at that time showing the top of cement at 5592'. Unocal again perforated at 5397' and performed another cement squeeze. Another temperature survey was run and it showed only a 50' increase to 5347'. Again Unocal perforated at 5265' and performed another cement squeeze. However, there is no record that another temperature survey was performed. Roger’s believes there is possibly no cement over perforations at 4210'. Samson should be required to run a cement bond log to verify the isolation of the San Andres Formation and an injection profile survey run to determine where the injected water is going.

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[2] Pump cement out the bottom perforations to circulate to the top perforations.

The Unocal Injection Profile log dated July 1982 shows that the tubing packer was set at 4966' and not 5161' as shown on the W-14 application. There needs to be verification of the packer setting depth. Further the injection profile log shows that the top perforation is 5266' but injection fluid is moving outside the casing as high as 5210'. The conclusion written on the injection profile survey states "indicated hole in pipe or unreported perforations from 5210'-5266'. Temperatures indicate fluid moving below LTD." Though Samson has provided a calculated top of cement above the San Andres behind pipe, there has been no cement bond log or temperature survey to substantiate the top.

In 1994, Rogers ran a casing inspection log on its well. The results show that there is lighter weight casing across the San Andres interval. Though the rest of the well has 20# and 17# pipe, the casing inspection log purports to show some 15.5# pipe. The 15.5# pipe has a lower collapse pressure, 4040 psi. The casing inspection log showed metal loss from 5800'-5900'. The collapse resistance for the new 4" liner placed in the well is 5110 psi. The liner has now been exposed for many years to the corrosive environment of the San Andres and does not cover the entire San Andres interval. As casing pitting occurs, the collapse strength diminishes rapidly. A tenth of an inch pit will reduce the collapse strength by 50%.[3] Additionally, there is no such thing as a perfect cement job on a 4" liner run inside a 5 ½" casing.

Though the gross thickness of the disposal interval in the disposal well is 256', Roger's believes that only the lower section of the disposal interval, about 60' of 19% porosity, is most likely taking all the water because the upper portion is tight (originally the upper section was all that was opened and it had to be fracture stimulated). It was not until after approximately 700,000 BW were injected that the lower interval was perforated and opened up. Roger's water displacement calculations are based on: 60' of injection interval @ 19%` (symbol for porosity), from 1973-1994 approximately 2.9 MMBW were injected which calculates 44,221 bbl/ac and if assuming a 50% movable pore volume, the calculated invaded area is 67 acres (964' radius). The Stitt No. 1 is approximately 1200' from the subject disposal well and watered out from a San Andres casing leak in February 1995. In May 1995, the Laura Cotten No. 1 watered out and it is just a little farther away. Based on the watering out of the Stitt No. 1 and the Cotten No. 1, the true injection interval is 60 feet and not the 256' used by Samson. Increasing the disposal volume to 6000 BWPD the water front projection shows that in year 13, the injected water would reach the Shrecengost well.

Of greater concern is the increase in reservoir pressure that may result in possible casing collapse. From 1973-1992 approximately 2.6 MMBW were injected and for the last three years ['90-'92] the average rate was 913 BWPD. The reservoir pressure in the San Andres is 2,558 psi. Using the same 19%` and 60' thickness, the pressure at the Rogers well would be 2,751 psi, a pressure increase of 193 psi. From the workover history of the Rogers well in 1992, there was a note included that stated the observed casing pressure had built up to 200 psi, thus Rogers asserts that its

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[3] S.K. Rogers Oil Exhibit No. 36. Casing Strength Degradation Due to Corrosion - Applications to Casing Pressure Assement, IADC/SPE 88009, Kai Sun, University of Houston, Boyun Guo and Ghalambor Ali, University of Louisiana at LaFayette, IADC/SPE Asia Pacific Technology Conference and Exhibition in Kuala Lumpur, Malaysia, 13-15 September 2004.

use of 60' thickness is substantiated. If the application is approved and the volume is increased to 6000 BWPD, the pressure increase in one year at the Roger's well will be 3,131 psi (an increase of 573 psi). If Samson were to continue to inject at this rate for 10 years, the pressure would be 3,666 psi (an increase of 1108 psi).

Rogers believes that the pressure increase will provide the strong likelihood of crossflow in the following wells:

1.) The Bison Petroleum, Bill McGowan Well No. 1 is 2300' from the injection well. This well watered out in 1995 and plugged in 1996. The 5 ½" casing was cut off at 5521' which is essentially in the middle of the injection zone interval. The bottom plug set in the well does not cover the entire perforated interval 9953'-9992' of the Canyon producing zone. The calculated top of the plug, according to the plugging report is 9960'.

2.) The shut-in Laura Cotten well, also a Canyon well, watered out in May 1995 and again there was no cement behind casing across the disposal interval. This well is only shut-in and has been for many years. The vertilog survey run in 1979 indicated pits from 7228' to 7230' and possible hole at 5742' which is very close to the base on the injection interval. Rogers believes this well should have at least a bottom plug placed in it as there could be a fluid confinement issue and the well is closer to the Rogers well.

3.) The Seaton No. 1 is 3000' from the subject disposal well. There is a casing leak at 5181' and only a straddle packer assembly from 5,068' to 10,753' was placed in the well. There is no cement behind pipe. If another casing leak were to develop, the water would/could enter below the upper straddle packer and then enter the Canyon perforations above the lower packer. Again, the Rogers well in the Canyon could possibly be severely impacted.

Rogers believes it is not a mere coincidence that the Cotten, Stitt No. 1 and the Bill McGowan wells all had casing leaks in the San Andres Formation in an area where the subject disposal well is located. Indeed, the San Andres water is corrosive <u>but</u> the increase in reservoir pressure caused by the disposal well has shortened the life of the above cited wells. There are three undeniable facts: the corrosive nature of the water, the lack of cement behind pipe and the increased reservoir pressure which will collapse the casing because of the weakened casing from corrosion.

REBUTTAL OF SAMSON

Rogers believes that the Stitt No. 2D watered out the Stitt No. 1 which in turn one month later watered out the McGowan well (1125' away). Further the Stitt No. 1 watered out the Cotten well (1350' away). The McGowan well is 1200' from the Schrecengost well. If, as Rogers believes the McGowan well is not properly plugged and there is cross flow from the San Andres water into the Canyon, the Schrecengost well should have been affected. However, the well has not had any problem in the 8 years after the McGowan well was plugged. Obviously, the McGowan well is properly plugged.

In reference to the Cotten well and the deep pits and possible hole as reported by the vertilog survey, the well was pressure tested shortly thereafter to 2000 psi and there were no holes as the pressure held.

Samson believes that Roger's estimate for lost reserves is unrealistic. Rogers used an unreasonably low economic limit and an almost flat decline rate. Samson performed reserve analysis on several Canyon wells which completely refutes Roger's estimation.

EXAMINERS' OPINION

Statewide Rule 9 - - Disposal Wells - - Subsection (6) "Subsequent commission action(A) "*A permit for saltwater or other oil or gas waste disposal may be modified, suspended, or terminated by the commission for just cause and opportunity for hearing, if:*" (v) "*...injected fluids are escaping from the permitted disposal zone; or* (vi) *waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.*"

The San Andres formation water is a highly corrosive, naturally occurring fluid. This is a well known historical fact. Operators had the opportunity to cement their casing strings across this interval but elected not to for various reasons. The casing leaks in the Rogers well were not caused by the injected fluids from the Samson well. Those injected fluids have not encountered the Roger's well some 3300' distant. It is then asserted that if the injected fluids have not actually reached its well, the pressure front has/or will and that results in casing collapse. The casing collapse will result sooner because of the deterioration of the casing. The predicted pressure increase by Rogers is less than the designed casing collapse pressure for even the "lite" (15.5#) casing that is across the disposal interval in the Rogers well. Though the well was not drilled and completed by Rogers, and Rogers was not the operator at the time the lighter weight casing was placed across the injection interval, certainly Samson can not be held accountable.

The pressure front analysis utilized by Rogers errs in determining the reservoir pressure at its well for the period of time from 1973 to 1992. The analysis assumes a flat injection rate (based on the average of the last 3 years) for the entire 20 year time period. Using a rate of 913 BWPD for the entire period equates to a disposal volume of 6.665 MMBW when only 2.6 MMBW were actually injected. Thus, the calculation results in an overestimated reservoir pressure at its well. The superposition analysis utilized by Samson is the correct reservoir engineering method for cases with varying injection rates. Pressure front calculations are more volume rate sensitive than thickness sensitive or small porosity differences. Pressure transients in a reservoir are accurate only to an order of magnitude. Throughout a reservoir, there are permeability differences, thickness differentials and other heterogeneities. The Rogers well is 3,300' from the subject disposal well. Thus any calculated pressure increase due to the subject well can not be viewed as absolute.

Essential in the water front (invaded area) calculation is the thickness of the zone taking water. Rogers asserts that only 60' of the perforated interval is accepting water whereas Samson asserts the entire 256' of perforated interval is accepting water. To a lesser degree, there is some argument concerning porosity but this is not an order of magnitude controlling parameter in this case. The greater the interval (thickness) accepting water, the lesser the area invaded. The San Andres Formation is considered 100% water saturated (no depletion) and an original pressure of 2,558 psi (water gradient x depth). Therefore, as water is injected, is there 100% displacement of the initial formation water? Probably not. However, 100% displacement is an appropriate assumption unless there is laboratory core analysis to substantiate otherwise. Rogers assumes a 50% water movement i.e. any water injected will take the place of 50% of the water currently in place. This assumption increases the invaded area. Even under this assumption, the injected waters have not reached the Rogers well.

The subject disposal well was perforated from 5,266'- 5,391' from 1973 to 1983 in the upper San Andres. Approximately 700,000 barrels of water were injected during that time. In 1983, the well was perforated from 5,420' - 5,590', thus increasing the interval to 256'. Rogers asserts that upper interval was so tight that Unocal had to fracture stimulate the interval to take water. After the lower interval was opened (and not fracture stimulated) only about 60' of that interval was prolific enough to take the injected water. The examiners believe this is an unreasonable determination. As in any perforated producing well, the zones opposite the perforations will yield fluid into the wellbore at different flow rates based on porosity, permeability and pressure differential. The opposite is true with an injection well. Upon the opening of the lower set of perforations, the upper zone had already received 700,000 barrels and the lower zone accepted the lion's share of the water injected during the transient state. However, with time and the volume of water injected, the lower interval would reach a pressure equilibrium with the upper interval until near semi-steady state conditions are attained. As this point is reached, each perforation interval will take fluid based on its individual permeability/porosity (*k* `) fraction of the entire perforated interval. This is the behavior seen in thick, layered reservoirs and each layer has its own fractional flow. The evidence submitted assumes a common permeability of 25 md. However, a detailed foot-by-foot analysis of porosity determination was presented. Therefore, it is an error to assume only 60' of interval accepted water from 1983 forward and the assumption results in an exaggerated calculated pressure front determination.

Past casing leaks may have caused other wells to have watered out because an operator did not recognize the fact in a timely matter. Rogers believes there are wells still present or that may have not been properly plugged in the past still providing conduits for possible cross-flow from the San Andres to the Canyon or other zones. Confirmation that plugged wells are properly plugged i.e. cement plugs placed properly to insure confinement, is necessary because it would be almost impossible to determine if there was fluid movement. Producing/shut-in wells may be monitored, through various methods, through the tubing-longstring-surface casing annuli to determine if communication is occurring. Rogers asserts this casing leak/crossflow scenario in the Laura Cotten Well No. 1 - a shut-in well or the Seaton Well No. 1 with a straddle packer or an improperly plugged well, the Bison Petroleum, Bill McGowan Well No. 1. The Laura Cotten and the Seaton wells are surface wells that can be monitored.

If the Bill McGowan well was not properly plugged i.e. the cement plug rising high enough from the cast iron bridge plug at 9980' to cover the top perforation at 9953', Rogers asserts there potentially could be a migration avenue for San Andres water to move from the disposal interval down the McGowan well bore and enter the unprotected Canyon perforations. The well is approximately 1200' from the Rogers well. Samson believes that the well was properly plugged in 1996 based on the fact that eight years have now passed and there has been no adverse affect on Rogers well. Rogers assertion that a casing leak in the Stitt No. 1 created an avenue that caused the watering out of the Cotten and McGowan wells (at approximately the same distances from the Stitt No. 1 as the Rogers well is from the McGowan well) within just a few months of the Stitt No. 1 casing leak may have been accurate, but those avenues have been closed. Pursuant to Commission plugging rules and stated on the McGowan plugging Form (W-3) the well was circulated with 10 lb/gal mud. The wellbore is not an empty annulus from the disposal interval to the CIBP at the Canyon interval.

Finally, there is no evidence to indicate that the operation of this well will adversely impact the water quality of any nearby surface water or subsurface usable quality water.

The examiners recommend that the application be approved to increase the maximum volume of disposal to 6000 BWPD at a maximum surface injection pressure of 2,350 psig. The recommendation is based on the following special conditions:

1. Perform a workover on the subject well to determine if a plug is set at 7,550'. If not, the casing will be perforated and a 50 sack cement squeeze will be performed (tagging of the plug is required).

2. Perform a survey (cement bond log/temperature log/or other technologically approved method by the district office for making such determinations) that will verify the top of cement outside the casing above the permitted top (4,706') of the disposal zone. If said survey does not show such impermeable cement confinement barrier, a 75 sack cement squeeze shall be performed at 4,706' and a subsequent survey (cement bond log/temperature log/or other technologically approved method by the district office for making such determinations) will be run to verify the top of cement.

FINDINGS OF FACT

1. Notice of this hearing was given to all persons required to be given notice by the provisions of Statewide Rule 9. Notice of this hearing was given to all affected persons, at least ten (10) days prior to the date of the hearing.

2. The subject well was originally permitted, March 1, 1973 Permit No. 03832, as a disposal well to Union Oil Company of California in the interval from 5,266' to 5,391' subsurface depth and a maximum surface pressure of 1000 psig.

   a. The permit was amended June 8, 1983 (Union Oil), to enlarge the disposal interval from 4,706' to 7,550' and increase the maximum surface injection pressure to 1500 psig. Perforations were added from 5,420' to 5,590'.

b. On April 19, 1990, the permit was amended (Union Oil) to increase the maximum injection pressure to 1,800 psig and established a maximum disposal volume of 2,000 BWPD.

3. Samson now proposes that the maximum disposal volume be increased to 6,000 BWPD and the maximum surface injection pressure be increased to 2,350 psig.

4. The well is completed as follows:

   Surface casing (11-3/4") is set at 332' and cemented from the casing shoe to the ground surface.
   Intermediate casing (8-5/8") is set at 4,730' and cemented from the casing shoe to a calculated top of 3,523'.
   Longstring casing (5-½") is set at 10,114' and cement from the casing shoe to a calculated top of 3,903'.
   Tubing (2-3/8") is set at 5,155' on an Otis Permalatch Packer at 5,161'. The perforated interval is from 5,266' to 5,590' in the San Andres Formation.

5. The depth to the base of the deepest fresh water is 300'.

6. There are no producing wells within the 1/4 mile required area of review. There are four properly plugged and abandoned wells within the 1/4 mile review area.

7. The disposal zone is the San Andres Formation and is a thick, relatively uniform, continuous formation across the entire area.

   a. The naturally occurring San Andres Formation water is highly corrosive.

   b. Numerous wells dispose of produced water into the San Andres Formation in Terry County and surrounding county areas. Maximum injection volume rates range from 300 to 20,000 BWPD and maximum permitted disposal pressures range from 2,000 to 2,550 psig.

8. Area producing wells are completed in the much deeper Canyon, Strawn and Fusselman Formations.

   a. Numerous wells completed in the deeper reservoirs did not have cement behind casing across the San Andres Formation zone.

   b. The corrosive nature of the San Andres water does cause metal deterioration which may result in casing leaks.

9. Use of the proposed disposal well is in the public interest because it will provide needed saltwater disposal capacity for the leases connected to the disposal system thereby increasing

the recovery of reserves by an estimated 265,600 barrels of oil.

10. The S.K. Rogers, Shrecengost "B" Well No. 1, completed in 1992, is the only active producing well in the Brownfield, South (Canyon) Field and is located approximately 3,300' from the subject disposal well.

    a. The Shrecengost "B" Well No. 1 has had numerous casing leaks as the San Andres interval is from 5370' to 6040' and the longstring casing was not initially cemented across the San Andres Formation interval.

    b. In 1998, Rogers ran a 4" partial liner (4,646' to 6,559') inside the longstring casing across the San Andres Formation interval and cemented it in place. There have been no casing leaks in that well since that time.

11. All plugged and abandoned wells within 3,300' of the subject disposal well have been plugged in such a manner as to prevent fluid migration from the intended disposal zone to other formations productive of oil or gas.

12. The operation of the subject well will not adversely impact the water quality of any nearby surface water or subsurface usable quality water.

13. Samson Lone Star LP has a $310,000 bond (Form P-5) on file with the Commission as its financial assurance.

CONCLUSIONS OF LAW

1. Proper notice was timely given to all parties entitled to notice pursuant to applicable statutes and rules.

2. All things have occurred and have been accomplished to give the Commission jurisdiction in this case.

3. The use of the proposed injection well will not endanger oil, gas, or geothermal resources or cause the pollution of surface water or fresh water strata unproductive of oil, gas, or geothermal resources.

4. The applicant has complied with the requirements for approval set forth in Statewide Rule 9 and the provisions of Sec. 27.051 of the Texas Water Code.

5. The use of the proposed injection well is in the public interest pursuant to Sec 27.051 of the Texas Water Code.

6. Approval of the application will prevent waste of hydrocarbons that otherwise would remain unrecovered.

EXAMINERS' RECOMMENDATION

Based on the above findings and conclusions, the examiners recommend that the application of Samson Lone Star LP to amend its existing disposal permit to increase the disposal volume and pressure for its Christova Stitt Lease Well No. 2D be approved as set out in the attached Final Order.

Respectfully submitted,

Thomas H. Richter, P.E.
Technical Hearings Examiner
Office of General Counsel

Marshall Enquist
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